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Practical Problems in Combining Electric Power Production with Sea Water Desalination

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FOREWORD

This is one of a continuing series of reports designed to present accounts of progress in saline water conversion and the economics of its application. Such data are expected to contribute to the long-range development of economical processes applicable to low-cost demineralization of sea and other saline water.

Except for minor editing, the data herein are as contained in a report submitted by the contractor. The data and conclusions given in the report are essentially those of the contractor and are not necessarily endorsed by the Department of the Interior.

FOREWORD

The San Diego Test Facility primarily consists of two experimental distillation plants using steam extracted from a modified pre-existing steam turbine generating unit which is owned and operated by the San Diego Gas & Electric Co. Being the first large scale combination of water & power cycles, it has provided a unique opportunity to evaluate the practical problems which have arisen. Most are discussed in detail, but it should be emphasized that these particular problems may not be entirely representative of those which would occur with large dual-purpose plants designed specifically for dual cycle operation.

The reports' remarks and conclusions should not be construed to imply a negative attitude concerning the project's feasibility to those not familiar with the particular circumstances of this installation. The intent is simply to point out the problems which have occurred and provide sufficient detail for those making studies for the future to evaluate the possibility of re-occurrence and their effect on physical design and economics.

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by

Jon P. Hardway

INTRODUCTION

The following attempts to explain some of the major operating problems incurred during the first year's operation of a large scale combined power & desalination cycle. It is not primarily written for those already in the power production industry, but rather for those who are becoming associated with and affected by it for the first time. The comments apply primarily to problems associated with operation of the Multi-Stage Flash Test Module rather than the Senator Clair Engle Desalting Plant due to its larger size having a greater effect on power plant operation.

Much of the material is necessarily related to a particular system but it still should serve as a starting point when considering future designs. Electric power system requirements are ever changing and induce changes in generating equipment operating modes that can quite easily affect predicted operating and cost parameters of combined water and power production installations.

For convenience, the discussion has been divided into separate subjects as follows:

a. Description

b. Power vs Water Demands

c. Power Generating Capability

d. Interruptible Power Supplies

e. Turbine Crossover Extraction Control

f. Condensate Quality Control

g. Coordination of Operation

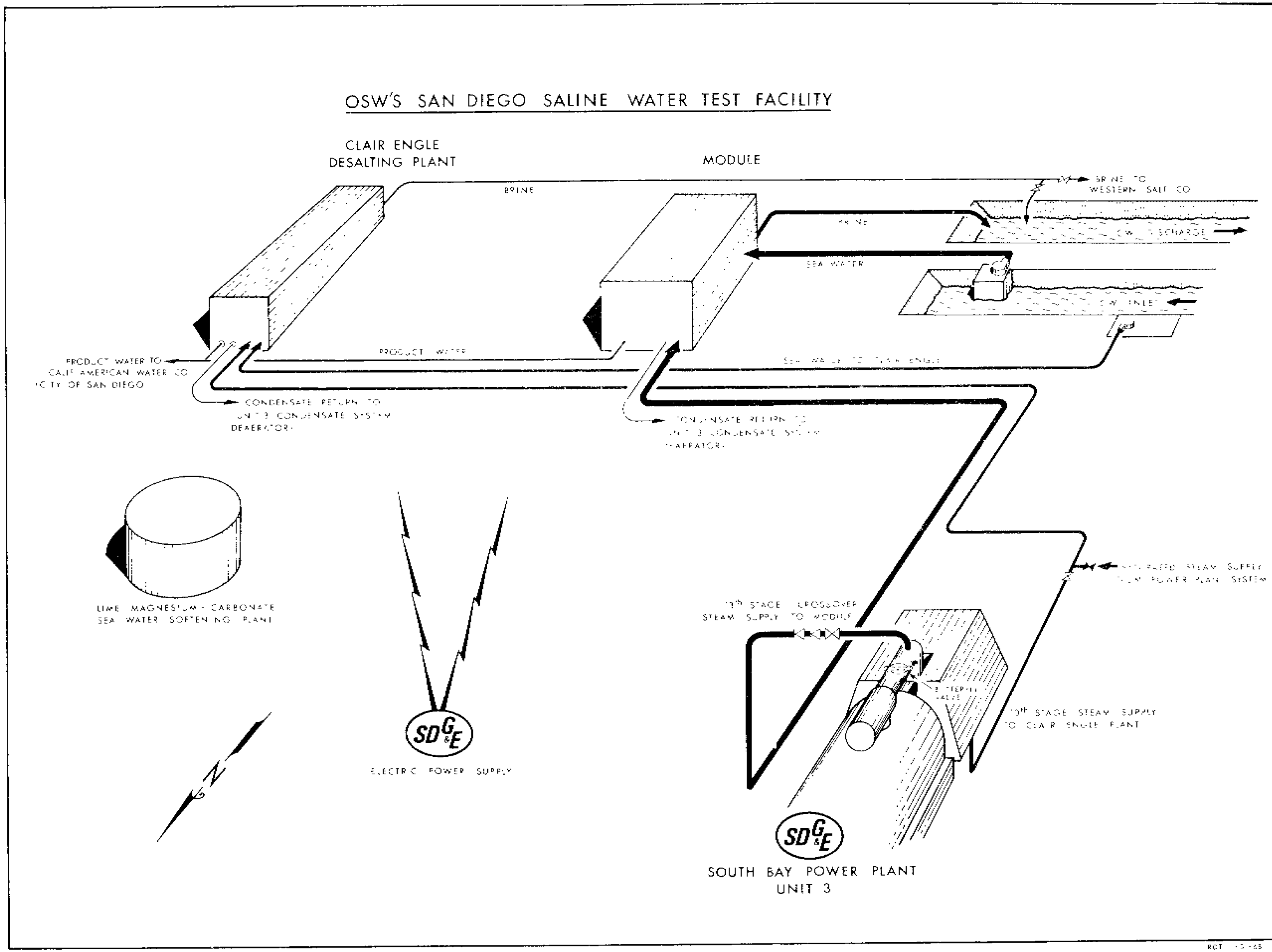
h. Conclusions

DESCRIPTION

On October 14, 1966, the San Diego Gas & Electric Company signed a License Agreement with the U.S. Department of the Interior's Office of Saline Water to effect the first large scale "marriage" of steam power production with desalination of sea water. At the present time, combined cycles include OSW's one million gallon per day full thermal cycle Senator Clair Engle Plant and the first Multi-Stage Flash Test Module, a full scale portion of a 50 mgpd plant capable of producing 2.5 mgpd of product water. Both are based on the flash distillation principle. San Diego Gas & Electric Company licensed the use of up to 20 acres of their South Bay Power Plant property to OSW to construct the San Diego Test Facility. Steam for the brine heaters and ejectors is primarily supplied by extraction from the Power Plant's Unit 3 Turbine. Condensate from the brine heaters is returned to the Unit 3 condensate cycle at a point after the low pressure feedwater heaters but before the deaerating heater.

Figure "1" is a simplified diagram of the combined cycles while Figures "3" and "4" show the two cycles in greater detail. The boiler is a Riley Stoker gas and oil fired turbo-fired unit capable of supplying 1,151 Mlb/hr of steam under normal operating conditions of 2150 psig at 1000 F & 1000 F reheat. It also has a peaking capability to supply 1,422 Mlb/hr at 2575 psig at 950 F/950 F. The turbine is a General Electric 3600 Rpm tandem compound double flow unit rated at 167.7 Mw with normal throttle steam conditions of 2000 psig, 1000 F/1000 F, and 1.5 in. Hg exhaust pressure. Its peak rating is 210.5 Mw with throttle steam conditions of 2400 psig, 950 F/950 F, and 2.0 in. Hg exhaust pressure. The turbine drives a 224 Mva hydrogen and oil cooled generator at 90% power factor. Hydrogen pressure is normally maintained at 30 psig and increased to 45 psig under peaking conditions. The condenser is a Westinghouse 111,900 sq ft, 2 pass surface condenser with 1 in. OD 90-10 Cu-Ni tubes, a divided hotwell, and epoxy lined fabricated steel water boxes.

Major auxiliaries consist of two hotwell or condensate, two boiler feed, and two circulating water pumps, each designed for 50% of peak load capability. Make-up water is purchased from California-American Water Co., softened by a sodium zeolite softener, and then evaporated by any or all of the power plant's one submerged tube and two flash evaporators. Maximum evaporative capacity for the three units is 33 Mlb/hr or 66 gpm. Excess make-up water is stored in two 50 M gal and one 100 M gal surge tanks having a combined usable capacity



OSW'S SAN DIEGO SALINE WATER TEST FACILITY
CLAIR ENGLE
DESALTING PLANT
MODULE
BRINE
SEA WATER
PRODUCT WATER
SOUTH BAY POWER PLANT
UNIT 3

FIGURE 1

of 180 M gal.

The steam supply to the Module is shown pictorially by Figure "2" and schematically by Figure "3". A specially designed crossover was installed between the intermediate and low pressure turbine sections (13th Stage) with a modulating butterfly valve (VX 300) included. A 24 in. line branches from the crossover before the butterfly valve to supply the Module brine heater with up to 500 Mlb/hr steam flow. The 24 in. motor operated gate valve (VX 302) serves as a shut-off valve for both normal and emergency operating conditions. Final steam pressure and temperature is regulated within the Module boundary.

Steam to the Clair Engle Plant, similar in concept as shown by Figure "4", is normally supplied by 10th Stage extraction up to 23 Mlb/hr through a 10 in. line. Its pressure and temperature is controlled within the power plant perimeter and condensate from the power plant cycle is used for desuperheating. A standby supply of steam from the Power Plant Units 1 & 2 saturated steam system is also installed to cover the periods when Unit 3 is out of service for an extended period such as during annual overhaul or when higher pressure steam than that available from the turbine is required by the distillation plants.

Condensate from both the Module and Clair Engle Plant's brine heaters is pumped through separate lines back to the power plant cycle. Because of the temperatures involved, it is returned directly to the power plant deaerating heater

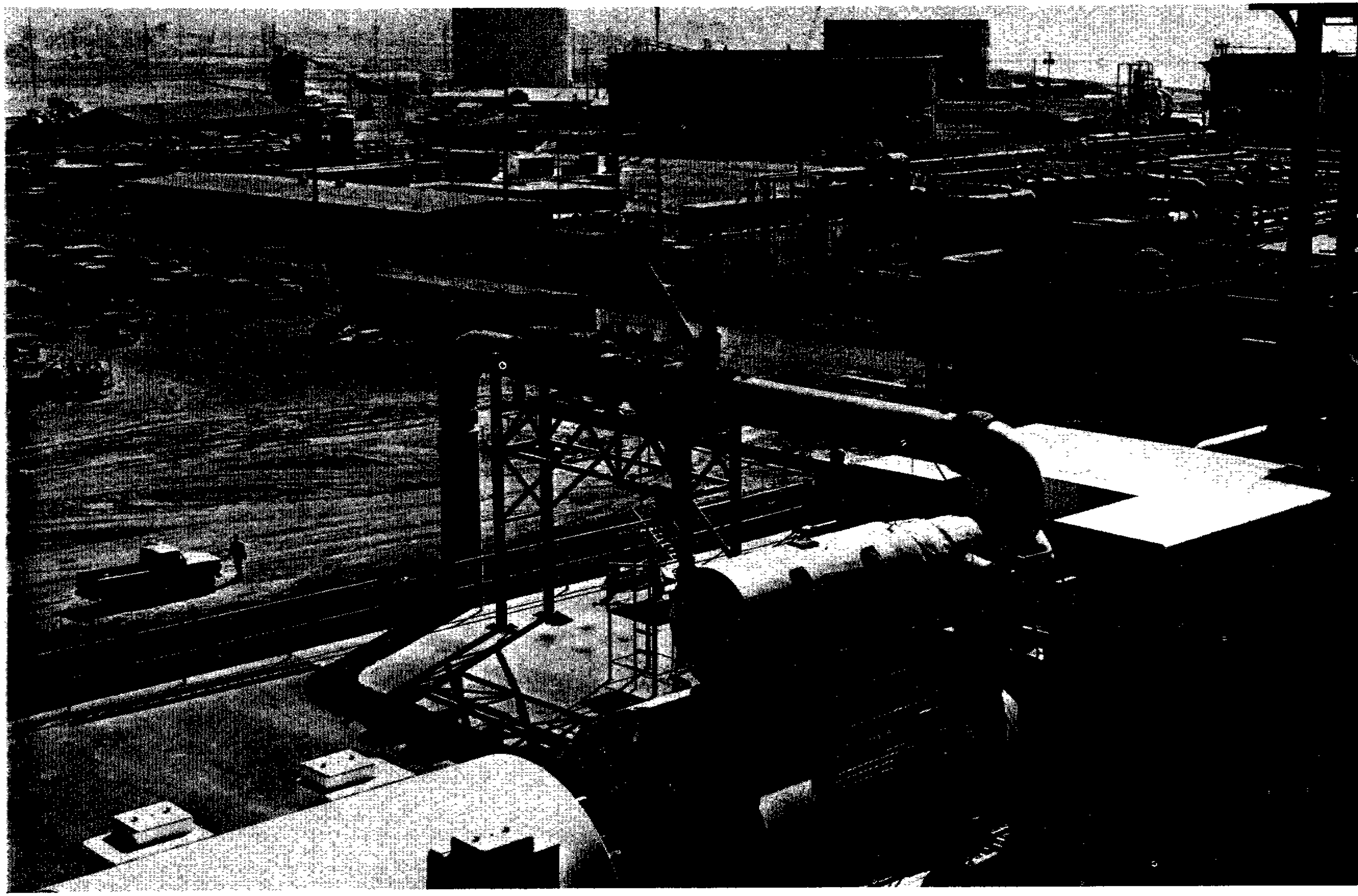
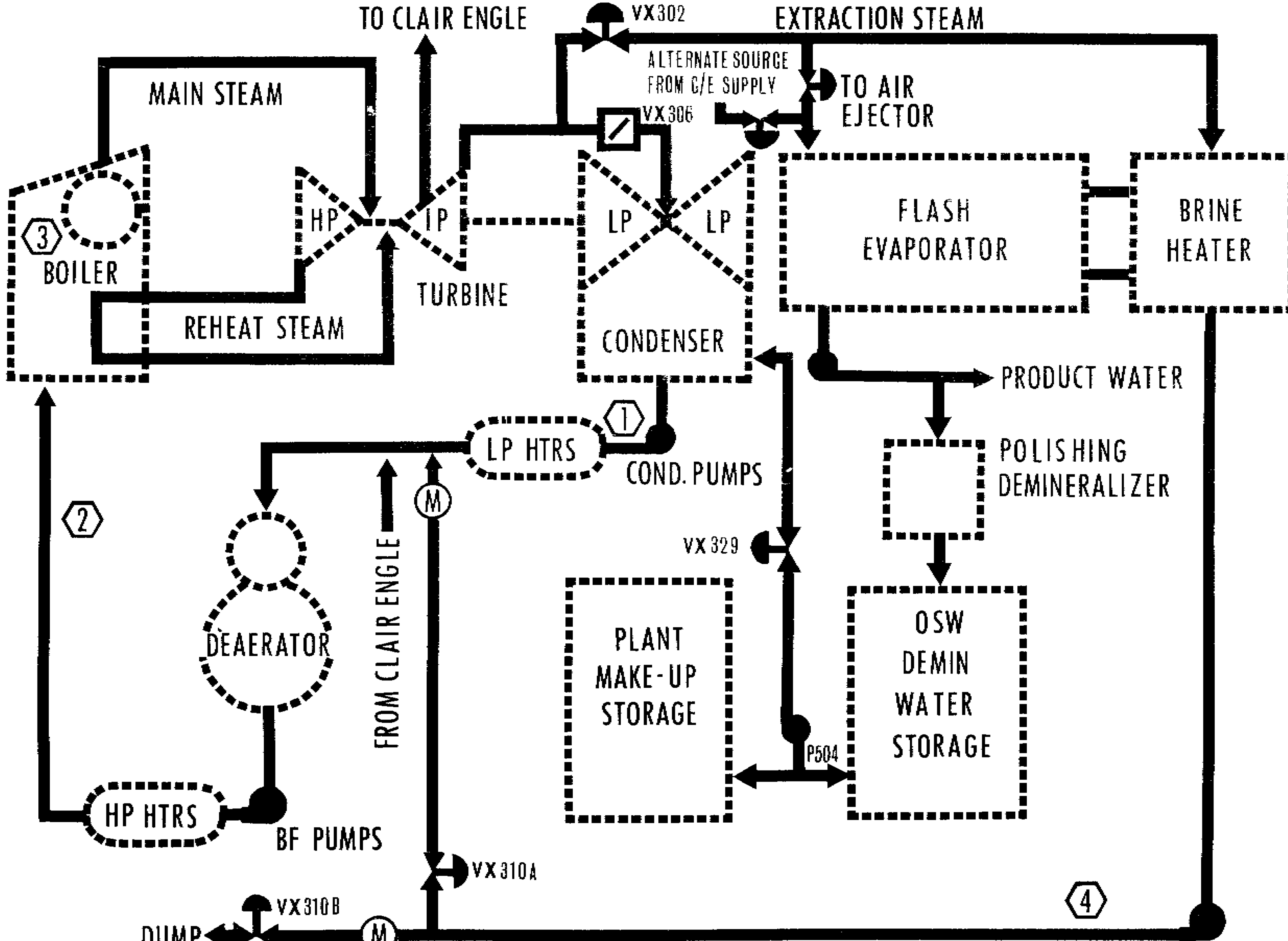


FIGURE 2



M Flow Meter

Conduc. Cell

Figure 3 South Bay Unit 3 Combined Cycle with the Test Module

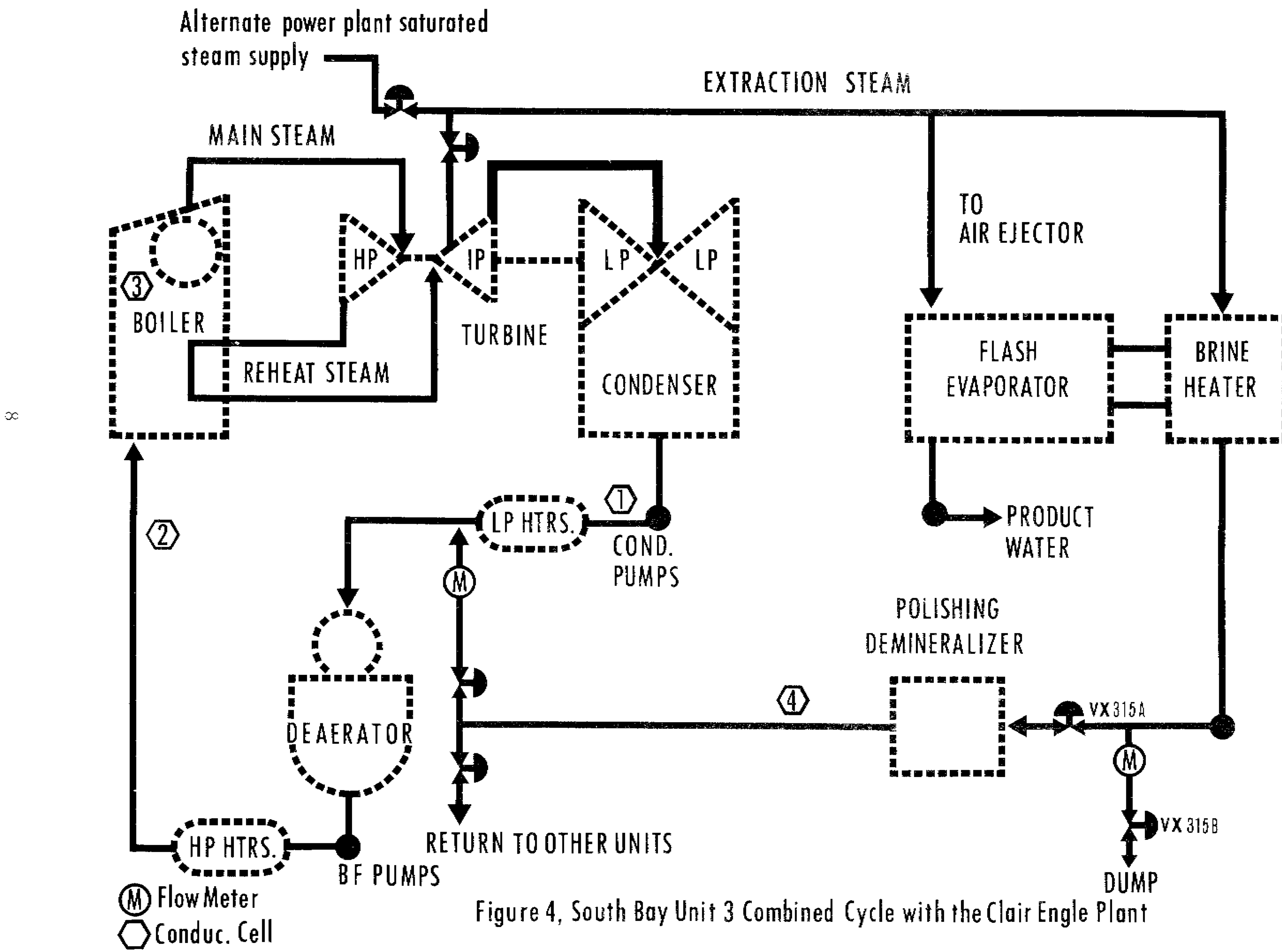


Figure 4, South Bay Unit 3 Combined Cycle with the Clair Engle Plant via the power plant make-up systems in the case of Clair Engle, and to the condensate system between the fourth low pressure heater and the deaerator as shown for the Module in Figure "3". The power plant make-up system is utilized for the Clair Engle return so the condensate may be returned to a unit other than Unit 3 if saturated steam from Units 1 and 2 is being used.

One other difference is that the Clair Engle condensate return system includes a non-regenerative demineralizing polisher as returned condensate temperatures prevented the use of a regenerative type. The initial costs of a similar demineralizer to handle the approximately 20-1 greater volume returning from the Module precluded a similar installation on that system. Unfortunately, the polisher manufacturer has yet to achieve satisfactory operation of his equipment.

Both condensate return systems have automatic condensate dumping systems controlled by conductivity cells to divert any contamination away from the power plant cycle. Under dumping conditions, the quantity dumped has to be replaced within the power plant system. The amount used by the Clair Engle Plant is normally only 17.5 Mlb/hr at rated output and is within the capability of the power plant make-up system if needed to maintain their operation.

Module condensate dumping represents a different problem. Its 360 Mlb/hr steady state usage at rated output with its present operating mode for simulating the low temperature end of a 50 mgpd plant represents over 30% of the turbine throttle flow with the turbine at rated load. The percentage obviously increases at lower turbine loading. The increase of Module consumption to 500 Mlb/hr with the planned simulation of high temperature end operation increases the problem. As the quantities of such make-up are obviously beyond power plant capabilities, an additional source of make-up condensate for the power plant cycle was required.

A separate 100 M gal tank has been provided to supply this make-up. The tank is normally kept filled with demineralized product water of a quality suitable for the power plant cycle. When the Module condensate return is dumped due to contamination, the OSW make-up pump (P 504) automatically starts and provides the necessary make-up to the power plant cycle via a control valve (VX 329) and a perforated header just above the hotwell divider in the condenser. Although this involves a control transition by returning the condensate to the condenser hotwell instead of the deaerator, it has introduced no cycle control problems. The intent of this feature was to allow sufficient time for either a correction of the contamination or an orderly shutdown of the Module. This can range from 1½ to 2 hours with the Module at rated output depending on its operating mode. Replenishment of this supply depends on the 50 gpm or 25 Mlb/hr product water demineralizer capacity and/or availability of power plant condensate in its own storage tanks. The latter source will be substantially lessened with the 1971 addition of Unit 4 to the power plant, as comparatively little additional make-up capacity is contemplated.

POWER VS WATER DEMANDS

Two basic assumptions seem to be valid. The first involves the fundamental difference between supplying electric power & water. Power must be generated at the instant it is in demand, no more and no less. In its own form of energy, it cannot be stored during the low consumption periods and utilized during peak demands. The water supply industry, on the other hand, has a historical background and practice of using reservoirs for storage to meet their peak demands. In other words, it seems logical that load demands for power production must take precedence over water production where there is conflict.

The second correlative assumption lies in the value of electric power. Because of the instantaneous unyielding demand during peak loads, its value primarily depends on peak period availability. Off-peak-only power, therefore, has a lower value. The net effect is to assign a penalty to water production to compensate for the added electrical system fuel cost imposed by the use of less efficient generating units required to make up the unavailable generating capacity because of water production. The penalty involved is of greater magnitude during peak periods as replacement power generation must be shifted further to older and more inefficient units. A similar penalty also applies during low power requirement periods if the generated load has to be maintained at a higher output than its most efficient level in relation to other units. This penalty concept also applies to long term operation in that a particular generating unit's early constant base load status will undoubtedly change to variable economic loading concepts as larger, more efficient units are added to a growing system.

PROBLEMS IN MEETING ELECTRIC POWER DEMANDS

Figure "5" shows typical electric power requirements over a 24-hour period. The system shown has its annual peak load on a weekday during the winter which is assumed to be 100%. Demand characteristics are also shown for winter Sundays and holidays which represent the low point during that season. Similar curves are also shown for the lower demand weekday and Sunday-holiday periods during the summer. Saturday demands generally fall between the weekday and Sunday-holiday curves and are not shown. The more important considerations with respect to maintaining constant water production rates involve the extremes of winter peak loads (100%) and night time "valleys" (30-35% of maximum annual demand).

The right side of Figure "5" are "building block" arrays (columns A thru E) of scaled unit capabilities in ascending order of: a base loaded nuclear plant, incoming tie line power for peak periods, and conventional power plant & gas turbine driven units of generally decreasing sizes (in percent

TYPICAL
SYSTEM LOAD CURVES - SUMMER & WINTER

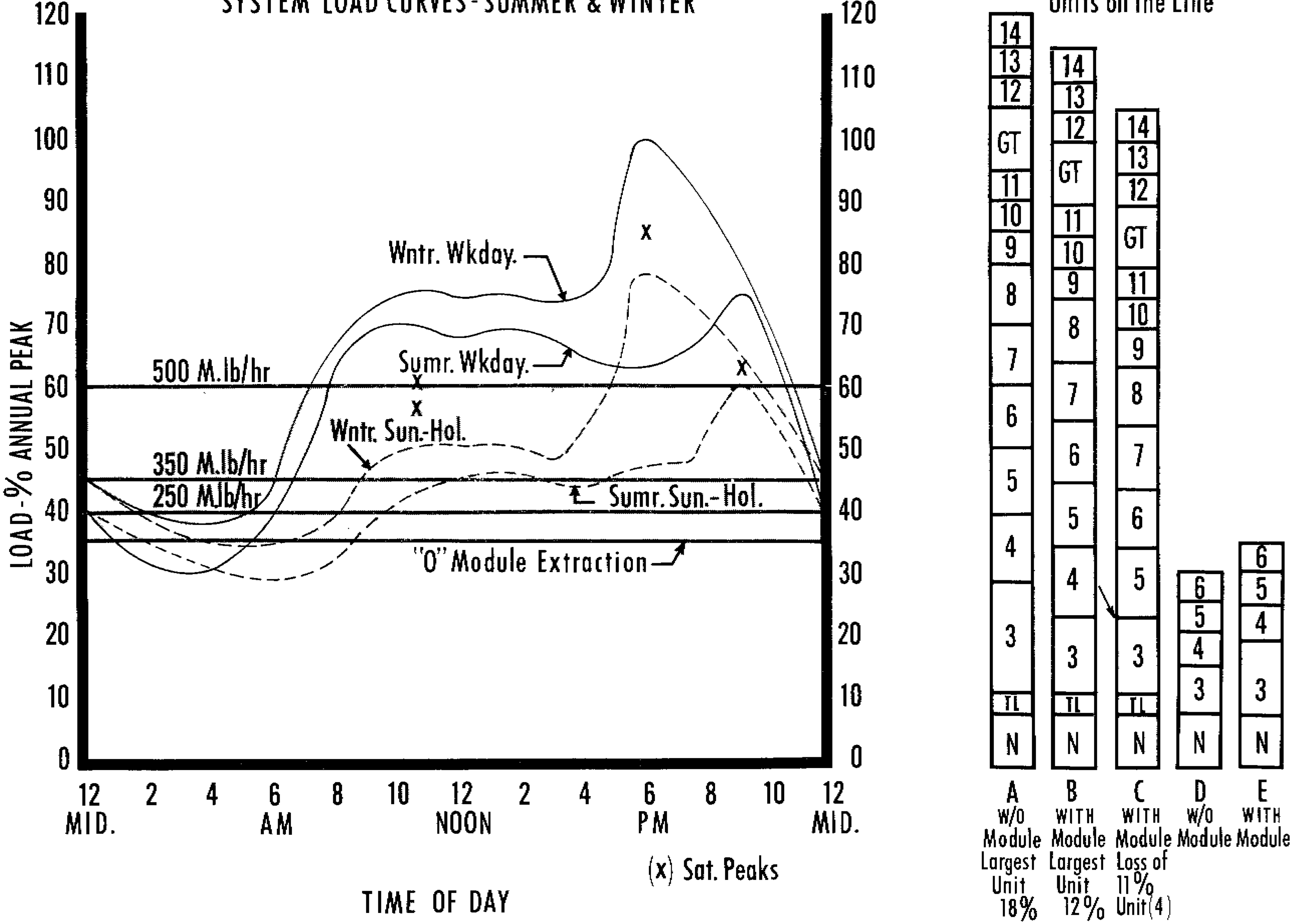


FIGURE 5

of annual peak demand) and efficiencies. Unit number 3 represents the unit combined with the desalination test facility and shows three capabilities: peaking capability without extraction to the Module (19%), normal capability without extraction to the Module (15%), and reduced normal capability with rated extraction to the Module (12%). Total number of units and their scaled capabilities are approximate only and simply serve for illustrative purposes.

A power system is designed so its minimum total in-service capability is such that its peak demands can still be met without the largest unit being available for service. If there is, as in this particular case, a contractural immediate demand requirement to supply neighboring utilities with up to 5% of the daily peak demand, the system capability must be either 105% of peak system demand or 100% plus the greatest load being generated by any one unit, whichever is larger. In this case, Unit 3's peak capability, without Module extraction being utilized, is assumed to be 18%. Therefore, the total system capability must be 118% of the annual peak demand.

Optimum planning, of course, would result in having only enough units in service at any time capable of generating the load plus the necessary margin. Column A shows the number of units in service to carry the winter peak assuming no extraction to the Module and Unit 3 is already in the peaking mode at maximum load. A total of 14 units or sources are shown capable of 120% of the peak load which is ample margin for the unscheduled loss of Unit 3's 18% or to supply the 5% contract demand.

Column B shows a similar set-up showing the different condition involved while extracting steam to the Module. Turbine limitations prevent going into the peaking mode while such extraction is being made which reduces its ready capability from 18% to a range of 12-15% depending on the amount of steam being extracted. With this capability reduction of the largest unit, the ready reserve requirement drops to 12-15% level which is still within the 14 unit block's capability thru the peak period. "Ready reserve" is the unused spinning reserve capacity of units already in service. The alternate is a contractural "half hour capability" which is reserve capacity which can be in service providing power within a half hour from call. Unit 3's peaking capability is contracturally considered half hour capability unless it is already in the peaking mode because of the time required to change.

Should one of the larger units, such as Unit 4, trip off the line, however, a new situation exists as shown by Column C. The maximum available capability is sufficient to meet the peak load but insufficient to meet the contractural or system ready reserve requirement. Under these system emergency conditions, the quickest restoration of the required capability is the reduction or interruption of the extraction steam flow to the Module. This capability is also contracturally considered to be half hour capability although slightly less than two minutes is required.

Columns D & E illustrate the other extreme during the system load "valleys" in the early morning hours. The nuclear unit is still base loaded providing the same amount of power as during the peak periods. There is no incoming Tie-Line power. The most efficient units remain in service and although the units shown as Blocks 6, 7, & 8 are less efficient, they are located at the opposite end of the system. Good operating practice dictates that at least one, and sometimes all three, be kept in service to avoid having all units in service located in a single plant or geographic area.

This creates an additional problem to that previously mentioned concerning ready reserve capability and this is one of minimum loading of units in service. Although units can be generally reduced to 30% or less of their rated capabilities, practical minimums require higher values that will enable the units to increase load rapidly in case of a system emergency. Columns D & E therefore show minimum practical loading with the minimum number of units in service for system reliability during the "valleys". The minimum allowable loads may be also increased if gas fuel curtailment is such that a combination of fuels is required on one unit. This has the effect of raising minimum loading from 30 to 50% on the particular unit(s) so affected as two fuel flow control valves would be on their minimum stops instead of just one.

Column D indicates that minimum loadings are just under the expected minimum system load and there is obviously sufficient capability to cover any reserve requirements. Column E, on the other hand, indicates that the minimum load on Unit 3 while extracting the future 500 Mlb/hr rated steam flow to the Module will increase the normal "valley" period generator output from 8% to 12%. With the other required units in service, the practical minimum loading is in excess of the generation requirements. The obvious remedy is to reduce extraction to the Module to the point that reduced generation of Unit 3 will allow minimum loading of Unit 6 and yet stay within load requirements. Fortunately, the rated steam flow to the Module with its present mode of operation with few exceptions has presented no problem to date.

Not included in the above illustration is the additional probable necessity of having another unit, Unit 7, on spinning reserve at absolute minimum load during this period in preparation for the rising demand following the low load period.

All the above has assumed all units available for service for the annual peak demands. The situation is not necessarily changed during the lower summer demand seasons. It is during this period that one or more units are removed from service for annual overhaul so the available capacity relative to the demand remains substantially constant. This is another way of saying that this is a year round problem.

What effect do these varying system load conditions have on the operation of the Module? If it can be assumed that all units are available and are placed in service in the order shown, automatic economic control of incremental loading will vary Unit 3's electrical loading to some degree in proportion to the system loading. The four horizontal lines on Figure "5" indicate the available quantities of extraction steam for the Module at various times of the day if no consideration were given for desired amounts. Whenever the system load is above 60% of the annual peak, the maximum 500 Mlb/hr extraction to the Module is available. The bottom line indicates the system load below which Unit 3 would be loaded so that no steam would be available for the Module. Two other lines are shown indicating that for system loads above 40% or 45% of the annual peak load, 250 & 350 Mlb/hr extraction steam would be available. History has shown that Unit 3 loading has not been forced down to the point that no steam is available to the Module but it does show periods when the supply has been limited to the 200 to 250 Mlb/hr range.

Referring again to Figure "5", it can be seen that economical generation of electrical power requires advance programming of units in and out of service. Load Programming Supervisors try to predict the load curve pattern each morning for the 24-hour period of the following day. Each power plant, in turn, provides its units' capabilities for setting up this program. Friday's programming covers a 72-hour period thru Monday. It can be seen that close planning coordination on a continuous basis by both power & water producers is essential to avoid the expense of having too many units in service or reducing the water production rate because insufficient steam is available.

Communication seems to be one of the major problems without any intended fault by any of the parties concerned. Both groups, power & water, naturally have their own objectives which are not always completely compatible during a given period of time.

POWER GENERATING CAPABILITY

Figure "6" is a typical annual load duration curve for Unit 3 without factoring in the extraction of steam for the Test Facility. It can be seen that peaking capability above 178 Mw Gross was utilized for 2.4% of the time. This is no longer available while extracting steam to the Module for turbine protection. Module extraction further reduces the output of the generator approximately one megawatt for each 13,500 lb/hr of extraction (see Figure "7"). The cost of transferring this reduction in load to less efficient units was factored into the cost of steam so this is not a problem from an economic standpoint.

However, it is necessary to maintain a minimum gross load of 105 Mw to supply the present rated extraction demand of 360 Mlb/hr if no minimum interface steam pressure is required. Recent acceptance tests requiring a minimum interface pressure of 50 psig also required a higher minimum generator output of 118 Mw. From Figure "6" again, it can be

ANNUAL LOAD DURATION-SOUTH BAY UNIT 3, 1967

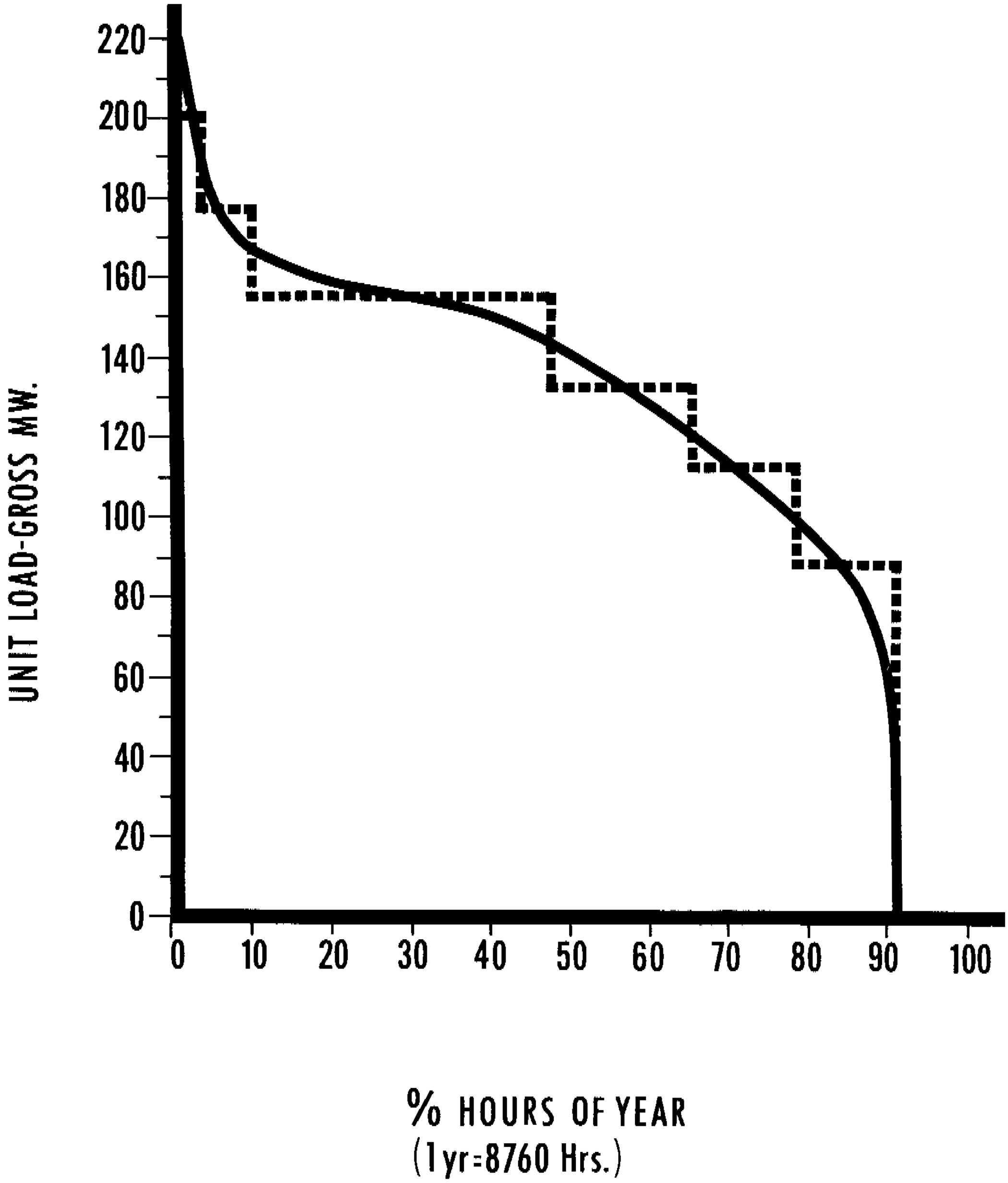


Figure 6

SOUTH BAY UNIT 3
MEGAWATT LIMITATIONS
VS
CROSSOVER EXTRACTION FLOW

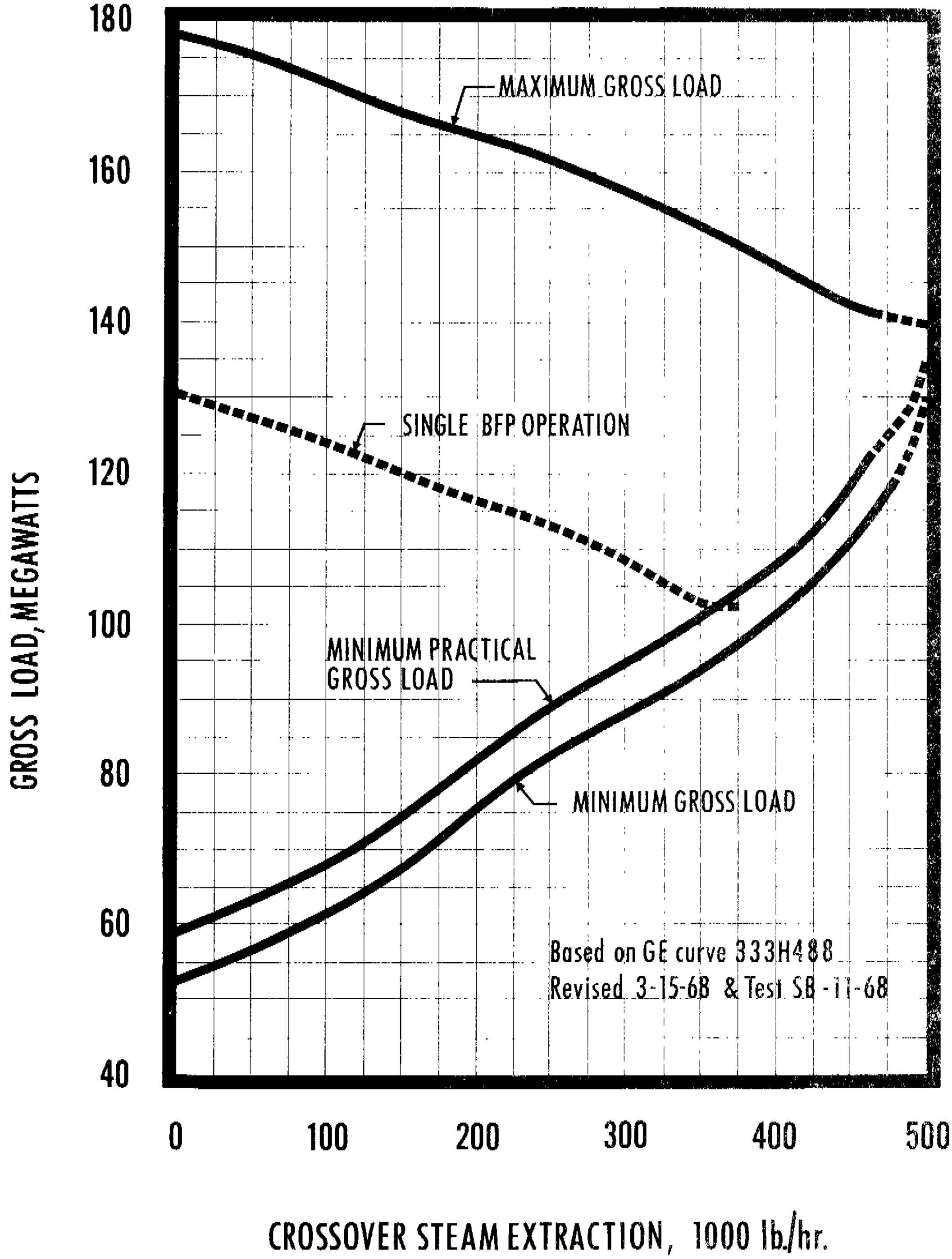


FIGURE 7

seen that such minimums require longer periods of generation above those normally expected during system "valleys" by economic load distribution among in-service units. This represents an additional cost of steam. It then follows that establishment of a constant 24-hour per day water production rate requiring a higher level of power generation than would otherwise be needed from an economic point will cause an increase in cost of electrical power or product water. The alternate of extracting steam from a higher stage during low generation periods has the same effect with respect to both steam & capital costs. All this leads to the conclusion that the optimizing of water costs in a combined cycle with a power plant requires consideration of the power company's present and future system load characteristics and its effect on the combined unit or plant.

INTERRUPTIBLE POWER SUPPLIES

To achieve the lowest possible costs, electric power is supplied to the entire Test Facility at their own substation on an interruptible rate schedule. The only foreseen event that would precipitate an interruption would be a system disturbance of such magnitude that shedding firm power customers would be required. Under these circumstances, interruptible customers should be shed first. Originally, a manually operated push button in the Power Plant control room served this function. However, a low frequency relay has been installed to automatically trip the supply at 59.2

Hz. This should eliminate the possibility of tripping too soon or too late due to the human factor.

Even though such an interruption may be and probably is a remote possibility, it still may create a problem for the OSW Test Facility operating contractors. They must evaluate and include safe shutdown plans for the equipment under their control in case of such a total power loss.

TURBINE CROSSOVER EXTRACTION CONTROL

As previously mentioned, steam for the Module is extracted from a specially designed 42 in. crossover between the intermediate and low pressure turbines. A 36 in. butterfly valve in the crossover operated by a high pressure hydraulic piston drive throttles the steam to the low pressure turbine while steam is extracted ahead of it to the Module through a 24 in. Gate Valve. Figures "7" & "8" show the operating characteristics with available extraction flows & pressures consistent with the turbine and generator loading.

The 36 in. butterfly valve was the largest available which resulted in some restriction in the crossover. The additional loss during non-extractive normal service with the valve blocked open was calculated to be 0.1% and tests indicated an 0.08% increase in heat rate at the current load factor. The butterfly valve not only serves to provide the highest possible extraction pressure consistent with turbine throttle flow but is also a part of the turbine protection control. The valve blade has a 1 in. radial clearance around

CROSSOVER EXTRACTION CONTROL SYSTEM

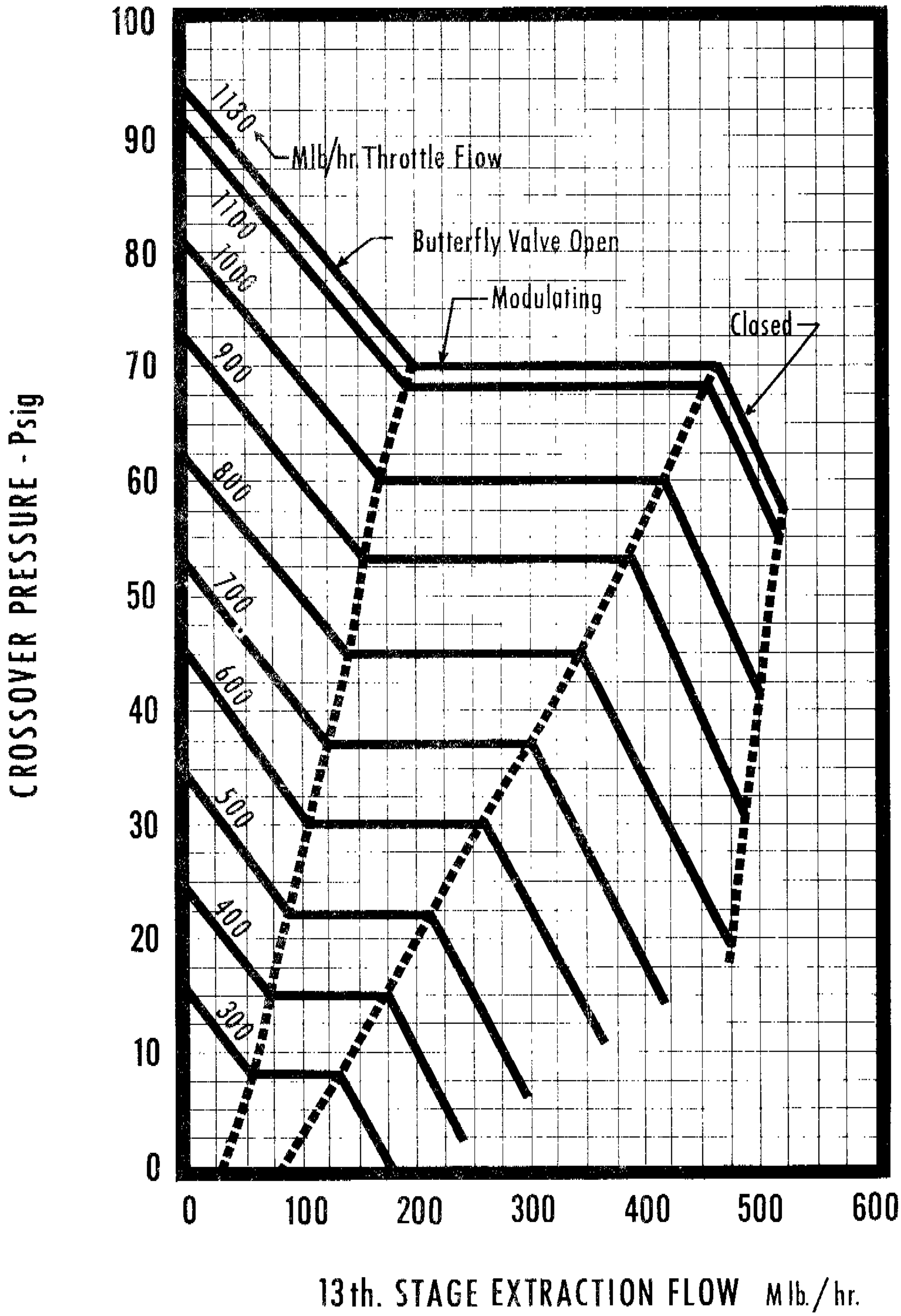


FIGURE 8

its circumference to provide cooling steam for the low pressure turbine should the valve completely close. For operating purposes, its range is from wide open to 15° from closed. Early operation disclosed some design and fabrication problems but correcting clearances and re-boring the body for proper shaft alignment has apparently corrected these deficiencies.

The 24 in. motor operated extraction line gate valve was originally equipped with a 12% chrome faced disk & bronze seat rings. Problems with galling of the seating surfaces resulted in an eventual change to "Stellite" facing on both disk & rings. So far, there has been no further galling or noticeable leakage when the valve is closed. A failure of the bronze yoke nut which is part of the valve motor operator raised some question as to the cause. For awhile it was not known whether it was an inherent failure of design, overstress due to the valve being installed in an upside down position, or too high a torque setting on the drive which was increased by the manufacturer in an attempt to seat the original valve. The consensus of opinion now indicates overstress due to the latter cause and the mechanical portion of the operator was replaced. A competitive electric motor valve operator installed in the 10th Stage Steam Extraction Line to the Senator Clair Engle Plant also experienced a similar failure. This may tend to indicate that electric valve operator manufacturers may still have room for improvement in frequent use applications.

The motor operated 24 in. gate valve in the extraction line serves as a shut-off valve when steam is not being extracted. Except for turbine temperature and differential problems, it is manually operated from the power plant control room. Should high temperature or high differential pressure across the intermediate pressure turbine blading occur, this valve will automatically close within two minutes with correlative action of the butterfly valve as part of the turbine protective controls. If this does not correct high temperature which can occur at any extraction flow, the turbine runback controls will then reduce unit load until the condition is corrected. Failure to do so will trip the unit off the line. Excessive pressure drop across the intermediate pressure stages will trip the turbine directly if the closing of the gate valve does not correct that condition before the differential increases to the trip point.

Continuing minor problems with the high pressure hydraulic system controlling the butterfly valve indicates that a second pump for back-up should be considered if increased reliability is desired for a permanent installation.

CONDENSATE QUALITY CONTROL

The Utility Services Agreement between OSW and San Diego Gas & Electric Company makes the steam supply contingent upon the condensate being returned in an "uncontaminated" condition. "Uncontaminated" is defined in the agreement as dissolved solids being no higher than the ratio of solids to water in the steam supplied or 25 parts per billion, whichever is higher.

Previous tests of steam quality indicate that 25 ppb is not an unreasonable limit although higher than is hoped for during normal operation. Unfortunately, tests for dissolved solids per se are not feasible for routine operating control. For such control, conductivity meters are used based on 2 mmho conductivity equalling approximately 1 ppm. This approximation fails in any exactitude because of the interference of Cyclohexylamine used to control pH of the power plant condensate as well as that of dissolved gases and ionized water. However, all is not lost as operating parameters of conductivity have successfully achieved adequate control as checked by periodic qualitative & quantitative water analysis and inspections of equipment.

Water quality control from an operating standpoint at South Bay is held within the following limits: Boiler water 10-20 mmhos with a ratio of approximately 3 to 1 of Sodium to Phosphate for a pH of 8.5-9.3 with no Sodium Chloride. Chlorides indicate the presence of sea water due to condenser or brine heater leakage with its inherently high boiler danger factor due to accompanying magnesium and calcium compounds. Silica control to prevent turbine blade deposits is also critical but this has not been a problem in conjunction with desalination due to the low silica content of sea water. Emergency measures for sea water leakage consist of increasing the free caustic content of the boiler water and blowing down.

Unfortunately, too much free caustic raises the spectre of caustic attack or accelerated corrosion of the boiler metal.[1]

Another major factor of system protection also involves the pre-boiler or condensate and boiler feed systems. Here, control limits have been established within a pH of 9.0-9.5 controlled by addition of Cyclohexylamine, and periodically dumping ammonia contaminated air ajector drains. Such controls result in a condensate copper content of less than 5 ppb and less than 10 ppb dissolved iron. Excess quantities also have a deleterious effect on the boiler water side which can only be remedied by acid cleaning.

Cation exchange columns are used in conjunction with conductivity equipment to remove the interference of ammonia and cyclohexylamine and to increase the sensitivity to chlorides by converting them to hydrochloric acid. The net result is that normal condensate and boiler feed conductivities at the point shown on Figures "3" & "4" are very close to one mmho. For example, a one mmho reading at points 1 & 2 with no undue increase at point 3 (boiler) water indicates normal conditions. An increase in points 1 & 2 with a resulting rise at point 3 usually indicates a condenser leak.

The introduction of condensate returned from the desalination brine heaters introduces another variable. An increase of conductivity at points 2 & 4 without an increase at point 1 resulting in an increase of boiler water conduct-

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[1]DENoll, "Factors that Determine Treatment for High Pressure Boilers", Proc Amer Pwr Conf, XXVI, 753-61 (1964)

ivity at point 3 would indicate contaminated condensate from the brine heaters. Accuracy of calibration of conductivity equipment has been questioned several times. However, experience has shown that normal patterns exist among the three independent instruments in the power plant cycle to the extent that a deviation in calibration of one is readily apparent. The result has been that a greater reliance has been placed on them to indicate adverse trends within the power plant cycle particularly in the case of brine heater contamination just under the alarm & dump point.

Quality control of condensate from the brine heaters therefore becomes a major factor in properly controlling the quality in the power plant cycle. This includes copper and iron contamination as well as sea water as major factors. Its effect is readily apparent when considering that the Module brine heater condensate may account for up to 44% of the total feedwater flow to the boiler. Fortunately, no adverse amounts of copper and iron have yet been detected. The Clair Engle Condensate Polisher & the Product Water Demineralizer are capable of removing these contaminants. A turbidity meter with an alarm provision has been installed in the Module condensate return line in an effort to protect against possible contamination from this source. The Module steam and condensate lines are highly suspect due to their comparatively long idle periods without steam or nitrogen blanketing to prevent oxidation.

A major problem for a while was sea water leakage at the brine heater. Fortunately such leakage is detected by a rise in conductivity. Based on the normal one mmho conductivities of the power plant pre-boiler cycle, the original maximum allowable return alarm setting for Module condensate return was 3 mmhos. Unfortunately, a few hours operation just under this level increased the chloride (and presumably magnesium & calcium compounds) content of the boiler water to the point that additional chemical treatment & heavy blowdown procedures had to be instituted. Other than the very real possibility of long term boiler damage, there is the immediate effect of decreasing the amount of available make-up to the point that continued operation of the conversion facility is not possible. As a result, the maximum allowable return was lowered to 1.5 mmhos conductivity with the control point held as close to the normal one mmho as possible. Early experience indicated that this value has created no out of the ordinary operating problem. It later developed that as the percentage of chlorides in the dissolved solids were greater than the normal make-up solids constituency, previous conductivity indices for solids content were no longer valid. Although the rate of chloride injection into the boiler has increased, it has not, to date, been of such greater significance to require a lowering of the control point.

The question has been raised whether a short term allowance of high conductivity return would be allowable to avoid a premature interruption of an important test. The answer generally should be primarily based on an equivalent to an emergency condition in an operating plant from the standpoint of frequency. The prime objective of a test bed plant is the running of tests and such requests could easily approach a frequency incompatible with good power plant operating practice. Experience again has often shown unrealized talent for correcting the conditions within a short time when firm alternatives of "clean up or dump the condensate" are given. In the case of Module brine heater leakage, recovery has been easily achieved by adjusting brine &/or steam pressures so the leakage is in the opposite direction. This would not be the case with a production flash plant's operating with its maximum brine temperature above 212 F.

COORDINATION OF OPERATION

A difficult problem has been in the field of inter-activity personnel communications on the operating level to achieve a fully coordinated operation. Control rooms are separate and communication is generally confined to telephones with little opportunity for personal rapport. This was made more difficult due to there being two separate organizations involved each with its own objectives of providing power and water which are seldom completely compatible.

In an effort to alleviate some of these problems, power plant operating personnel were given several training sessions on the theory and mechanics of multi-stage multi-effect flash evaporation. This coupled with on-site observation and their already versatile background encompassing the variety and complexity of power plant equipment and control gave them a broad understanding of the combined cycle and its problems. An offer was made to informally provide power plant familiarization tours which has been accepted to some degree. Where this has occurred, communications have improved on an individual basis. Mutual understanding of each other's operation and problems seems to be a key factor and a greater use of scheduled cross familiarization should be highly beneficial.

CONCLUSIONS

Optimum power and water production rates not always being compatible prevents full utilization of the investment in the water conversion equipment. This unfortunately has the effect of increasing either or both fixed & operating costs of producing water. Water storage alone is not the answer as the problem of a low load factor necessarily remains. Maintaining a constant water production rate in a combined water-power cycle requires a base loaded power production unit, means of extracting from a higher turbine extraction stage, or throttle steam, or use of brine as a heat storage medium as suggested by one author.[2] Nuclear units are presently operated at higher load factors than most fossil units and provide a more compatible load pattern for water production. One must not overlook considering the future, however, and try to predict

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[2] P.H. Margen "Hot Brine Energy Store" Energy International, 16-20 (May 1969)

their load pattern throughout their 30 to 40 year operating period. Alternate sources of steam have the effect of increasing both fixed and operating costs of producing water. Heat storage also requires a substantial investment and increases the complexity of turbine controls. It therefore becomes clear that the theoretical cost of producing water in a combined cycle is subject to many variables all tending to increase the cost relative to theoretical treatments of the costs.

It does not appear that interruptible power supplies without some back-up would be used in a combined plant specifically designed for the purpose. The possibility of a power interruption, however remote, does introduce the need for electrical controls and equipment to be designed for "fail safe" status in case of such a failure. This same criterion also applies to pneumatically operated controls.

Turbine extraction controls have generally proved to be satisfactory although high pressure hydraulic drive units need the same duplication of pumping units for continuity of operation as turbine manufacturers presently use for their new hydraulic governing systems. It appears feasible for the same equipment to serve both functions with turbines already so equipped.

Condensate quality control does not appear to be a problem in the present installation. It should be kept in mind, however, that utilizing a nuclear plant may impose more stringent conditions of returned condensate quality than have proved to be satisfactory in the present installation and may provide some difficulty. This would be particularly true in a single cycle nuclear plant using a boiling water reactor.

Too much emphasis cannot be placed on coordination of personnel on all levels. If it is not possible for the same organization to operate both the power & water production phases under common supervision, cross training of both groups in both operations remains a necessity for mutual understanding of each other's problems. It has been suggested that adjoining control rooms, if not a common one, would be highly beneficial in providing a continuity of closing the communication gap.

This discussion of practical problems has necessarily only covered the major highlights. Each day presents either a new one or a variation of a previous one. Fortunately, most are small, easily recognized and remedied and do not interfere with the basic concept of combined cycle operation.

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